TECHNICAL REVIEW DOCUMENT
For
RENEWAL of OPERATING PERMIT 95OPWE096

Thermo Cogeneration Partnership, L. P., a Delaware Limited Partnership
Ft. Lupton Cogeneration Facility
Weld County
Source ID 1230250

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Revised January and April 2006

I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed operating permit proposed for this site. The original Operating Permit was issued January 1, 1999. The expiration date for the permit was January 1, 2004. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal operating permit is issued and any previously extended permit shield continues in full force and operation. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted December 4, 2002, additional information submitted on January 15, 2003, December 14, 2004 and February 16, 2006, comments on the draft operating permit and technical review document received on February 3, 2006, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This facility consists of a cogeneration facility defined under Standard Industrial Classification 4931. Electricity for sale is produced by five (5) combustion turbines, equipped with duct burners. Each combustion turbine serves a generator rated at 57.412 MW (name-plate). Exhaust gas from the combustion turbine, which may be heated further by duct burners, is used to either generate electricity or to heat a nearby tomato greenhouse. There are two steam turbines, each rated at 52.220 MW (name-plate). Other significant emission units at the facility are a cooling tower, emergency back-up generator and fire pump.

The facility is located in Weld County at 6811 Weld County Road 31, in Ft. Lupton, CO. The facility is located in an area classified as attainment for all criteria pollutants, but is also located within the 8-hour Ozone Control Area as defined in Colorado Regulation No. 7, Section II.A.16.

There are no affected states within 50 miles of the facility. Rocky Mountain National Park, a federal Class I area is within 100 km of this facility.

Based on the information provided in the renewal application, no changes have been made to any of the significant emission units.

<u>MACT Requirements</u>

<u>Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)</u>

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the “MACT hammer”.

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. No Part 1 application was submitted for this facility, presumably because this facility was not a major source for HAPs. As part of the renewal application, the Division conducted its own analysis to determine whether the facility was a major source for HAPS. In its analysis, the Division evaluated HAP emissions using AP-42 emission factors. In general, except for formaldehyde emissions, the AP-42 emission factors are close to or more conservative than emission factors in an EPA memorandum dated August 22, 2003 for diffusion flame turbines greater than 50 MW using natural gas as fuel. For formaldehyde emissions, the EPA memo predicts higher emissions; however, because performance test data on these turbines indicate that the actual formaldehyde emission rate is less than AP-42, the Division used the AP-42 emission factors. Based on the Division's analysis the facility is not a major source for HAP emissions.

<u>Compliance Assurance Monitoring (CAM) Applicability</u>

Although the turbines are equipped with steam injection to reduce NO_X emissions, since the Title V permit specified a continuous monitoring method for NO_X the turbines are not subject to the CAM requirements as allowed by 40 CFR Part 64 § 64.2(b)(vi).

In addition, although the cooling water tower is equipped with drift eliminators, drift eliminators are not considered control devices as defined in 40 CFR Part 64 § 64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since the drift eliminators act as a passive control measure to prevent the release of pollutants (i.e. drift).

Finally, no other emission units are equipped with control devices; therefore, none of the remaining emission units are subject to the CAM requirements.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more specifically address the potential to emit and to update actual emissions. Emissions (in tons per year) at the facility are as follows:

	Potential to Emit (tons/yr)						
Emission Unit	PM	PM_{10}	SO_2	NO_X[1]	CO	VOC	HAPS
Turbine/Duct Burner 1 (S001)	16.81	16.81	2	589.	90.51	9.64	See Table on Page 16
Turbine/Duct Burner 2 (S002)	16.81	16.81	2		90.51	9.64	
Turbine/Duct Burner 3 (S003)	16.81	16.81	2		90.51	9.64	
Turbine/Duct Burner 4 (S004)	16.81	16.81	2		90.51	9.64	
Turbine/Duct Burner 5 (S005)	16.81	16.81	2		90.51	9.64	
Emergency Gen. (S006)[2]	0.27	0.26	0.59	3.81	1.49	0.26	
Fire-Pump (S007)[2]	0.07	0.07	0.14	1.52	0.25	0.07	
Cooling Tower (S011)[3]	9.5	9.5				1.23	
Total	93.89	93.88	10.73	594.33	454.29	49.76	10.55

[1]Each turbine/duct burner has individual NO_X limits, however, the total NO_X limits for all units is more restrictive, so the total limit is shown in the table.

[2]Emissions shown are from the original construction permits. Permitted emissions that were below the de minimis level (2 tons/yr) were not included in the original Title V permit and the subsequent renewal permit.
[3] VOC emissions are based on an emission factor of 0.0527 lb/mmgal for chloroform. Since VOC emissions are below the APEN de minimis level (2 tons/yr), the VOC emission limit is not included in the permit.

The criteria pollutant PTE shown above is based on permitted emission limits for the turbines, duct burners, engines and cooling tower. The breakdown of HAP emissions by emission unit and individual HAP is provided on page 16 of this document. The PTE of HAP emissions is based on AP-42 emission factors, permitted fuel consumption limits and heat values of 1020 Btu/SCF for natural gas and 137,000 Btu/gal for diesel fuel.

	Actual Emissions (tons/yr)						
Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS
Turbine/Duct Burner 1 (S001)	10.9	10.9	1.09	70	90.5	7.37	0.64
Turbine/Duct Burner 2 (S002)	10.9	10.9	1.09	70	90.5	7.37	0.64
Turbine/Duct Burner 3 (S003)	10.9	10.9	1.09	70	90.5	7.37	0.64
Turbine/Duct Burner 4 (S004)	10.9	10.9	1.09	70	90.5	7.37	0.64
Turbine/Duct Burner 5 (S005)	10.9	10.9	1.09	70	90.5	7.37	0.64
Emergency Gen. (S006)				3.81			
Cooling Tower (S011)	9.5	9.5					
Total	64	64	5.45	353.81	452.5	36.85	3.2

Actual emissions are based on the APENS submitted on December 14, 2004 and January 19, 2005. Reported actual emissions for the turbine/duct burners is based on “predicted highs” for all pollutants except for CO and for CO, the source reports potential to emit (i.e. permitted emissions) as actual emissions. The source also reports potential to emit (i.e. permitted emissions) as actual emissions for the cooling tower and the emergency generator.

III. Discussion of Modifications Made

Source Requested Modifications

The source submitted their renewal application on December 4, 2002. In their renewal application, the source requested that the Responsible Official and Permit Contact be changed. These changes have been made as requested.

In addition, the source submitted revised APENS for the turbines on December 14, 2004 and with the APENS, the source indicated that the two natural gas fired water chillers had been decommissioned and removed from the property and they requested that they be removed from the permit. This change has been made as requested.

Other Modifications

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Thermo Ft. Lupton Cogeneration Facility Renewal Operating Permit with the source's requested modifications. These changes are as follows:

Page Following Cover Page

- The citation (above "issued to" and "plant site location") on the page following the cover page provides the incorrect title for the state act. The title will be changed from "Colorado Air Quality Control Act" to "Colorado Air Pollution Prevention and Control Act". In addition, the dates were removed from the citation.

- Clarified dates for monitoring and compliance periods, i.e. changed "January - June" to "January 1 – June 30".

  It should be noted that the monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

- Added language specifying that the semi-annual reports and compliance certifications are due in the Division's office by the due date and that postmarks cannot be used for purposes of determining the timely receipt of such reports/certifications.

General

- The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3.

Section I – General Activities and Summary

- Revised the language in Condition 1.1 to indicate more specifically where the facility is located and to specify the size (i.e. MW) of the combustion turbines and associated steam turbine.

- Revised the language in Condition 1.1 to address attainment status of the area in which the facility is located.

- Conditions 13 and 17 in Condition 1.4 were renumbered to 14 and 18 and Condition 21 in Condition 1.5 was renumbered to 22. The renumbering changes were necessary due to the addition of the Common Provisions requirements in the General Conditions of the permit.

- The alternative operating scenario language was revised to current updated language. Note that the alternative operating scenario for permanent turbine replacement was removed. Since the facility is a major stationary source for PSD and was issued a PSD permit, any permanent turbine replacement would require a BACT analysis. For major stationary source the Division allows for temporary turbine replacement up to 270 days. We consider that this provides the source time to get a construction permit for any turbine replacement that is intended to be permanent. The temporary AOS does not address MACT applicability for any replacement turbine, it is expected that MACT applicability would be addressed during processing of the construction permit should the turbine be intended for use as a permanent replacement.

- Revised the Reg 3 citations in Condition 3.1 and added a Condition 3.2 to indicate that there are no other Operating Permits associated with this facility.

- Based on comments made by EPA on another operating permit, the phrase "Based on the information provided by the applicant" was added to the beginning of Condition 4.1 (112(r)).

- Added a "new" Section 5 for compliance assurance monitoring (CAM). Note that no emission units are subject to the CAM requirements.

Section II.1 – Combustion Turbines

Many of the associated changes have been made In order to change the format for this permit to make it more consistent with the format for the permits issued for the other utility turbines and to include requirements that may have been previously overlooked. Specifically, the changes were made as follows:

- The continuous emission monitoring system (CEMS) requirements were moved to a new condition 5 in Section II.

- Added a specific condition to identify BACT for the turbines. PSD review was required for NO_X, CO, PM, PM_{10} and VOC.

  Note that neither of the original construction permits (a separate permit issued for each turbine, initial approval issued February 19, 1992 or the combined permit issued as an initial approval, modification 1 on July 26, 1996) specifically indicated that PSD review applied to VOC emissions; however, the combined permit included a short-term emission limit (lbs/hr) for VOC, presumably as a BACT limit, since VOC emissions clearly exceeded the PSD VOC significance level and would have been subject to PSD review. Therefore, the Division will put the lbs/hr limit back into the permit for VOC emissions, since most likely this short term VOC limit was a BACT limit.

- Added language to the NO_X and CO BACT limits to clarify that the daily average shall be determined using all operating hours, include periods of startup, shutdown and malfunction, during every midnight-to-midnight period.

- Emission Factors. The emission factors included in the permit for the turbine are in units of lb/mmBtu and for the duct burners are in units of lb/mmSCF. The technical review document for the original Title V permit indicates that we specifically required that it was Division policy that the turbine emission factors be in units of lbs/mmBtu. The permit will be revised to include emission factors that are all in the same units (lbs/mmBtu).

  In addition, since the PM and PM_{10} emission factors for the turbines are from an older version of AP-42, the latest AP-42 emission factors will be included in the permit. Since these emission factors are lower (0.0066 lbs/Btu vs. 0.014 lb/mmBtu) than the current emission factors in the permit, no changes to the emission limits are necessary. Based on the review of the original Title V permit application it appears that those were the only AP-42 emission factors. Although the original Title V permit application indicates that the duct burner PM and PM_{10} emission factors were from AP-42, there was information in the files that indicated that those emission factors could also have been from the manufacturer. Therefore, the Division will not change the PM and PM_{10} emission factors for the duct burners and the permit will indicate that those emission factors are from the manufacturer.

In their response to comments received on February 3, 2006, the source requested that they be allowed to use the same emission factor for both the turbine and the duct burner. The source proposed to use the turbine emission factor for both the turbine and the duct burner. Results from the November 1997 performance test indicate that VOC emissions from both the turbine alone and the turbine and duct burner together are well below the emission factor in the current permit for the turbine. Therefore, the Division has revised the permit to require that VOC emissions from both the turbine and the duct burner be determined using the turbine emission factor.

- NSPS Db - The NSPS Db NO_X limit was not included in the original Title V permit. The technical review document for the original Title V permit indicates that since the NO_X emission factor for the duct burner is less than the NSPS NO_X limit (0.20 lb/mmBtu) the NSPS NO_X limit does not need to be included in the permit. The emission factor for the duct burner that was used to set the permit limits is not an enforceable limitation and is not even used in a compliance demonstration. Therefore, the Division considers that it was not appropriate to exclude the NSPS NO_X limit from the permit. Therefore, the NSPS NO_X limit will be included in the renewal permit.

  For compliance purposes, NSPS Db specifies that for duct burners the source can either conduct a one-time stack test or use a CEMS to demonstrate compliance with the NO_X emission limitation (per 40 CFR Part 60 Subpart Db § 60.46b(f), as adopted by reference in Colorado Regulation No. 6, part A). The NSPS Db provisions were not included in the initial approval construction permits for the turbines and duct burners (91WE667-1 thru –5, initial approval issued February 19, 1992 and initial approval, transfer of ownership issued September 3, 1993). The initial approval construction permits included performance test requirements for NO_X and CO, although information in the master files indicates that the continuous emission monitoring systems were used in lieu of the performance test for the NO_X and CO BACT limits and it appears that a performance test may have been conducted for the NSPS GG NO_X limits. The NSPS Db limit was included in a revised construction permit that was issued on July 26, 1996. That permit did not include a specific requirement to conduct a performance test for NO_X. A review of the information in the Division's files indicates that the source submitted a compliance plan on October 14, 1997 and this plan included a demonstration that the NSPS Db NO_X limit was less stringent than the BACT limits and the plan indicated that the source did not believe that any separate monitoring or recordkeeping would be required. The Division accepted the compliance plan in a letter dated October 15, 1997 and presumably at that time the Division believed that no performance test was required. While the Division could agree that a federal NSPS is less stringent than another emission limitation, such as a BACT limitation, the Division cannot exempt the source from the performance test requirement on the federal NSPS requirement.

  For duct burners NSPS Db provides two compliance demonstration options, either a performance test or the use of a NO_X CEMS (note that per 40 CFR Part

60 Subpart Db § 60.48b(h) NO_X CEMS are not required for duct burners). In their February 3, 2006 comments on the draft permit, the source has intended to use a 1995 performance test but upon further review, it appears that the performance test was not conducted with the duct burners firing. Therefore, in a February 16, 2006 e-mail, the source indicated that they would use the NO_X CEMS to monitoring compliance with the NSPS Db NO_X limitation. Since the source has elected to use their NO_X CEMS, the appropriate requirements from 40 CFR Part 60 Subpart Db § 60.48b (NO_X CEMS requirements) will be included in the permit. In addition, the applicable reporting and recordkeeping requirements from 40 CFR Part 60 Subpart Db § 60.49b will be included in the permit.

In addition, the below provisions from NSPS Db also apply to the duct burners:

- o The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor for each calendar quarter. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month (40 CFR Part 60 Subpart Db § 60.49b(d), as adopted by reference in Colorado Regulation No. 6, Part A).

- o All records required under this section shall be maintained for a period of 2 years (40 CFR Part 60 Subpart Db § 60.49b(o), as adopted by reference in Colorado Regulation No. 6, Part A).

  Note that the requirement to retain records for 2 years will be streamlined out of the permit, since Regulation No. 3, Part C, Section V.C.6 requires that records be retained for five (5) years.

- The construction permit and subsequently the operating permit included the requirements to record fuel hourly and steam hourly. Presumably these requirements were included in order to address the NSPS GG requirement, which states that turbines using water and/or steam injection must continuously monitor the fuel consumption and the ratio of steam to fuel being fired in the turbine. Since the turbines are equipped with a NO_X CEMS and the source is using the CEMS to demonstrate compliance with the NO_X emission limitations based on the revisions to NSPS GG (published in the July 8, 2004 Federal Register) it is no longer required that sources with water and/or steam injection must continuously monitor fuel and the ratio of water and/or steam to fuel (40 CFR Part 60 Subpart GG § 60.334(b)).

- The NSPS GG NO_X limit was not included in the Title V permit presumably because the construction permit indicated that the BACT limit superceded the NSPS GG limit. Although the NO_X BACT limit is more conservative than the NSPS GG NO_X limit, the averaging times are different, the NO_X BACT limit is a daily average, while the NSPS GG NO_X limit is a 4-hour rolling average. Therefore, the NSPS GG NO_X limit cannot be streamlined out of the permit since it cannot be determined that the NO_X BACT limit is always more stringent than the NSPS GG NO_X limit. Therefore, the NSPS GG NO_X limit will be included in the permit. Note that since the NSPS GG NO_X limit will be included in the permit, the NO_X CEMS requirements included in NSPS GG will also be included in the permit, as well as the excess emission reporting requirements.

- <u>Regulation No. 1 particulate matter and SO_2 requirements.</u> The Reg 1 particulate matter limits for fuel burning equipment and the Reg 1 SO_2 requirements for turbines have been included in the renewal permit. These requirements were not included in the original Title V permit. It may be that since the Reg 1 requirements were not included in the construction permit, they were overlooked and subsequently not included in the Title V permit.

- <u>Regulation No. 1 vs Regulation No. 6, Part B requirements.</u> The Reg 6, Part B, Section II state-only requirements for fuel burning equipment (particulate matter, opacity and SO_2 emissions) were not included in the original Title V permit. Again, it may be that these requirements were not included in the Title V permit because they were not included in the construction permit. However, the Reg 6, Part B requirements apply and need to be addressed in the Title V permit. The Reg 6, Part B particulate matter and SO_2 requirements are the same as the Reg 1 particulate matter and SO_2 limits. The Reg 1 requirements apply at all times. The Reg 6, Part B requirements are state-only enforceable and the Division considers that the Reg 6, Part B requirements do not apply during periods of startup, shutdown and malfunction since the Reg 6, Part B requirements incorporate the general provisions in 40 CFR Part 60 Subpart A (Reg 6, Part B, Section I.A). The general provisions in 40 CFR Part 60 Subpart A, specifically state that the opacity limits do not apply during periods of startup and shutdown (§ 60.11(c)) and various EPA policy memos have indicated that the provisions in § 60.11(d) exempt sources from the emission standards during periods of startup, shutdown and malfunction, unless the specific subpart states otherwise. For that reason, the Division considers that the permit should incorporate the Reg 1 particulate matter and SO_2 requirements and streamline the Reg 6, Part B particulate matter and SO_2 requirements. Therefore, the Reg 1 particulate matter and SO_2 requirements are referenced in the permit and the Reg 6, Part B particulate matter and SO_2 requirements are included in the permit shield for streamlined requirements (Section III.3 of the permit).

- <u>Opacity requirements</u>. Only the 20% opacity requirement in Reg 1, Section II.A.1 was included in the original Title V permit, the 30% opacity requirement in Reg 1, Section II.A.4, which applies under specific operating conditions was not included. It is not clear why the 30% opacity requirement was not included, therefore, it has been included in the renewal permit. In addition, as discussed above, the 20% opacity requirement from Reg 6, Part B was not included in the original Title V permit. As shown on the attached grid, none of the opacity requirements are more stringent at all times, therefore, all opacity requirements shall be included in the permit. The language in the permit for the 20% opacity requirement was revised to more closely match the language in the regulation. In the absence of credible evidence to the contrary, compliance with all of the opacity requirements is presumed whenever pipeline quality natural gas is used as fuel.

- Revised the language in the permit regarding the sulfur content of the fuel (Condition 1.4). The permit requires the source to sample the sulfur content of the fuel monthly and to keep a rolling twelve month average of the sulfur content to insure that the gas burned as fuel meets the definition of pipeline quality gas. The analytical methods are consistent with the methods specified in NSPS GG and the frequency of sampling is more frequent than that of NSPS GG (40 CFR Part 60 Subpart GG § 60.334(h)(3).

- Some of the NSPS general provisions listed were removed as they are addressed in the new Condition 5 for the continuous emission monitoring systems.

- Removed Condition 1.8 (run-time hours/good practices), this condition essentially addresses the NSPS good practices requirement and is therefore not necessary.

- Removed the 90% monitor availability requirements (Condition 1.1.1). Although the 90% continuous emission monitor availability requirement was included in some older construction permits, the Division no longer considers this to be an appropriate requirement to include in permits. The continuous emission monitoring system should meet the monitor availability requirements specified in 40 CFR Part 60 Subpart A § 60.13(d).

<u>Section II.2 – Emergency Generator</u>

- The Division has revised the NO_X emission factor for the engine. According to the original Title V permit application, the NO_X emission factor was from AP-42, Section 3.4, dated January 1995 (NO_X = 3.1 lb/mmBtu). Section 3.4 of AP-42 has been revised (October 1996) and the NO_X emission factor is slightly higher (3.2 lb/mmBtu). As in the original Title V permit, the emission factor was converted to units of lb/mmBtu based on a diesel fuel heat content of 131,890 Btu/gal.

- Revised the equation in Condition 2.1 to calculate emissions in units of tons per month.

- Revised and reformatted the language in Condition 2.2 (fuel usage).

- The Regulation No. 1 SO_2 limit was not included in the original Title V permit but will be included in the renewal permit. Based on the AP-42 emission factor (Section 3.4, table 3.4-1, dated October 1996), the Reg 1 SO_2 limit cannot be exceeded provided the weight percent sulfur of the fuel does not exceed 0.79 % by weight. Therefore, in the absence of evidence to the contrary, compliance with the Reg 1 SO_2 limit is presumed whenever diesel fuel is used as fuel.

- The Reg 1 30% opacity requirement included in the Title V permit indicates that it only applies during periods of startup. The Reg 1 30% opacity requirement actually applies under the following conditions: fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment. The Division considers that based on engineering judgment, the operational activities of fire building, cleaning of fire boxes and soot blowing do not apply to diesel engines. In addition, since this engine is not equipped with control equipment the operational activities of adjustment or occasional cleaning of control equipment also do not apply to this engine. Finally, based on engineering judgment, it is unlikely that process modifications will occur with the emergency generator. Therefore, for this unit the 30% opacity provision only applies during startup.

- On other permits, the EPA has objected to the use of the term “normal” and “special conditions” for opacity, since EPA considers that “startup” is a normal operating condition and not a “special condition” for an emission unit. So the 20 % opacity language (Condition 2.3) will be rewritten to remove references to “normal” and both the 20% and 30% opacity language will be rewritten to more closely resemble the language in Regulation No. 1.

- Added a requirement to monitor opacity emissions during startup and to specify that an opacity observation shall be conducted at least annually.

- Added a requirement to sample fuel semi-annually. The fuel sampling is required to verify that the sulfur content of the fuel does not exceed 0.79% by weight.

<u>Section II.3 – Diesel Fired Emergency Fire Pump</u>

- Revised and reformatted the language in Condition 3.1 (fuel usage).

- The Regulation No. 1 SO_2 limit was not included in the original Title V permit but will be included in the renewal permit. Based on the AP-42 emission factor, the Reg 1 SO_2 limit cannot be exceeded provided the weight percent sulfur of the fuel does not exceed 0.79 % by weight. Therefore, in the absence of evidence to the contrary, compliance with the Reg 1 SO_2 limit is presumed whenever diesel fuel is used as fuel.

- The Reg 1 30% opacity requirement included in the Title V permit indicates that it only applies during periods of startup. The Reg 1 30% opacity requirement actually applies under the following conditions: fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment. The Division considers that based on engineering judgment, the operational activities of fire building, cleaning of fire boxes and soot blowing do not apply to diesel engines. In addition, since this engine is not equipped with control equipment the operational activities of adjustment or occasional cleaning of control equipment also do not apply to this engine. Finally, based on engineering judgment, it is unlikely that process modifications will occur with the fire pump. Therefore, for this unit the 30% opacity provision only applies during startup.

- On other permits, the EPA has objected to the use of the term “normal” and “special conditions” for opacity, since EPA considers that “startup” is a normal operating condition and not a “special condition” for an emission unit. So the 20 % opacity language (Condition 3.2) will be rewritten to remove references to “normal” and both the 20% and 30% opacity language will be rewritten to more closely resemble the language in Regulation No. 1.

- Added a requirement to monitor opacity emissions during startup and to specify that an opacity observation shall be conducted at least annually.

- Added a requirement to sample fuel semi-annually. The fuel sampling is required to verify that the sulfur content of the fuel does not exceed 0.79% by weight.

<u>Section II.5 – Cooling Water Tower</u>

- Revised Condition 5.1 to more clearly identify the emission calculation method and assumptions. In addition, the equation was revised to calculate emissions in units of tons/mo rather than lbs/mo.

- Revised the language in Condition 5.2 (circulating water) to indicate that a twelve month rolling total shall be maintained to monitor compliance with the annual limitations.

- Revised the language in Condition 5.3 (sampling for TDS), to remove the requirement to use a Division approved method. Past inspection reports do not really indicate whether the Division actually approved the method used for obtaining TDS data; therefore presumably the Division has not had any concerns over the sampling and analysis methods used by the source. Therefore, the permit will be revised to require that the source maintain the analysis method on site and make that information available to the Division for review.

- Removed Condition 5.4 (odor). The Reg 2 odor provisions are included in the General Conditions (Section IV) of the permit and apply to the facility regardless of whether the provisions are included in Section II (Specific Permit Terms) of the permit. Since cooling towers are not necessarily considered to be a source that is generally associated with odors, the Division does not believe that it is necessary to include this requirement in Section II of the permit.

- The Reg 1 20% opacity requirement was not included in the permit. Presumably this is because it is generally expected that cooling towers will comply with the opacity limitations. While that may be the case, the opacity limits do apply and should be included in the permit. The renewal permit have been revised to include the Reg 1 20% opacity requirement.

- Regarding the Reg 1 30% opacity requirement. Based on engineering judgment, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling towers. In addition, there is really no "startup" involved in operating a cooling tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with these units.

<u>Section III – Permit Shield</u>

- The citation in the permit shield was corrected and revised to reflect the revisions to Reg 3. The reference to Part C, Section XIII was changed to Part C, Section XIII.B and references to Part C, Section V.C.1.b and C.R.S. 25-7-111(2)(l) were removed, since they did not address the permit shield.

- Based on comments made by EPA on another permit, the phrase "based on the information available to the Division and provided by the applicant" to the beginning of the justification for the shield for the PSD requirements.

- Based on comments made by EPA on another permit, the following statements were added after the introductory sentence in Section 1 "This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modification or reconstruction on which construction commenced prior to permit issuance."

- Added a section 3 for streamlined requirements. The streamlined requirements addressed in this table are discussed under the specific emission unit discussion in this document.

<u>Section IV – General Conditions</u>

- Added an "and" between the Reg 3 and C.R.S. citations in General Condition 3 (compliance requirements).

- Added language from the Common Provisions (new condition 3). With this change the reference to "21.d" in Condition 20 (prompt deviation reporting) will be changed to "22.d", since the general conditions are renumbered with the addition of the Common Provisions.

- The citation in General Condition 7 (fees) was changed to cite the Colorado Revised Statue. In addition, any specific identification of a fee (i.e. $100 APEN fee) or citation of Reg 3 was removed and replaced with the language "…in accordance with the provisions of C.R.S. [appropriate citation]."

- The citation in General Condition 13 (odor) was corrected. In addition, the phrase “Part A” was added to the citation for Condition 13 (odor). Colorado Regulation No. 2 was revised and a Part B was added to address swine operations. Colorado Regulation No. 2, Part B should not be included as a general condition in the operating permit.

- The citation in General Condition 16 (open burning) was revised. The open burning requirements are no longer in Reg 1 but are in new Reg 9. In addition, changed the reference in the text from “Reg 1” to “Reg 9”.

- Added the requirements in Colorado Regulation No. 7, Section V.B (disposal of volatile organic compounds) to General Condition 28.

<u>Appendices</u>

- First Page of Appendices – The phrase “except as otherwise provided in the permit” was added after the word “enforceable” in the disclaimer at the request of EPA.

- Appendix B and C were replaced with revised Appendices.

- The EPA addresses in Appendix D were corrected.

- Added ppm, ppmv and pppmvd to the list in Appendix D.

- Revised the Table in Appendix F to add a column for “type of modification”.

Total HAP Emissions (tons/yr) from Thermo Cogeneration Partnership - Ft. Lupton Facility

Emission Unit	formaldehyde	acetaldehyde	toluene	benzene	acrolein	xylene	chloroform	hexane	dichlorobenzene	nickel	cadmium	chromium	propylene	Total
All Turbines	3.76	0.21	0.69	0.06	0.03	0.34								5.09
All DBs	0.17		7.61E-03	4.70E-03				4.03	2.69E-03	4.70E-03	2.46E-03	3.13E-03		4.22
Emerg. Gen	1.31E-03	8.54E-04	4.55E-04	1.04E-03	1.03E-04	3.17E-04							2.87E-03	6.95E-03
Fire Pump	3.50E-04	2.27E-04	1.21E-04	2.76E-04	2.74E-05	8.44E-05							7.64E-04	1.85E-03
Cool Twr							1.23							1.23
Total	3.93	0.21	0.70	0.07	0.03	0.34	1.23	4.03	2.69E-03	4.70E-03	2.46E-03	3.13E-03	3.64E-03	10.55

The heating value of natural gas was presumed to be 1020 Btu/scf and the heating value of diesel was presumed to be 137,000 Btu/gal
HAP emissions for the turbines and duct burners are based on the total fuel consumption limit.